STATE OF CALIFORNIA

ELECTRICITY OVERSIGHT BOARD

Gray Davis, Governor

Update on Unscheduled Load Penalties Imposed by the FERC and IOUs Financial Capabilities

Staff Report
June 2001

Ben T. Arikawa
Senior Economist

Attachment A

This report updates an earlier review (dated March 22, 2001) of the assessment of the underscheduling penalty and the financial ability of the investor owned utilities (IOUs) to meet the "net short" position. This update contains more historical information about generation and load scheduling since late March and about the investor owned utilities (IOUs) financial liabilities.

Introduction and Summary

The December 15, 2000 Federal Energy Regulatory Commission Order (Order) imposed penalties on "underscheduling" by load serving entities such as PG&E and Southern California Edison (Edison). The penalty applies for load that is met in real time to the extent that it exceeds 5 percent of total load. The penalty is the lesser of $100 per MWh or twice the cost of real time energy. Since the real time price has rarely fallen below $100 from January 1 through May 31, the effective penalty is $100 per MWh.

Since mid-January, the State of California has stepped in as the provider of the "net short" position of the IOUs. Pursuant to SB 7X and AB 1X, CDWR has been given that responsibility. In the first 163 days of this year (January 1 through June 12, 2001), only on 37 days was there sufficient generation and load scheduled day ahead to avoid the FERC's penalty. I estimate that the potential penalty for unscheduled load approaches $1 billion through June 12, 2001 based on the generation and load unscheduled day ahead and average real time prices.

The financial status of the two largest investor owned utilities, Pacific Gas and Electric Company (PG&E) and Southern California Edison (Edison), have not measurably improved. Since the last report, PG&E filed for bankruptcy on April 6, 2001 and Edison has entered into a memorandum of understanding (MOU) with Governor Davis to purchase its transmission system on April 9, 2001. The California Public Utilities Commission has authorized rate increases of up

to 52 percent for certain retail tariff schedules. However, these increases, in general, were not for costs incurred in the past, but for payment of costs going forward. A portion of the increase was designated to flow through to the CDWR as partial payment for its purchases to cover the "net short."

Load Unscheduled Day Ahead

As mentioned previously, the CDWR has stepped in to be the purchaser of the IOUs "net short" position. CDWR has been purchasing power on a regular basis since January 19, 2001[1]. Generation and load unscheduled day ahead has, on a regular basis, exceeded the 5 percent deadband. (See Figure 1.) The percentage of unscheduled generation and load has varied from a low of negative 8 percent in early June to a high of 24 percent on February 8 and May 8.

Prior to the CDWR's authorization to begin purchases on January 19, generation and load unscheduled day ahead was approximately 20 percent. Unscheduled generation and load during weekdays through mid-February remained high, typically in the range of 15 to 20 percent. Unscheduled weekend loads were lower, usually ranging from below 5 percent to 10 percent.

Starting in late February, the unscheduled generation and load began to decrease due to milder weather and increased generation availability. This situation continued until the three week of March as loads increased due to warmer than normal temperatures. As temperatures fell and hydroelectric generation increased, unscheduled load rarely exceeded 10 percent through April. As temperatures and load began to increase through May, unscheduled load also increased, regularly exceeding 10 percent through most of May.

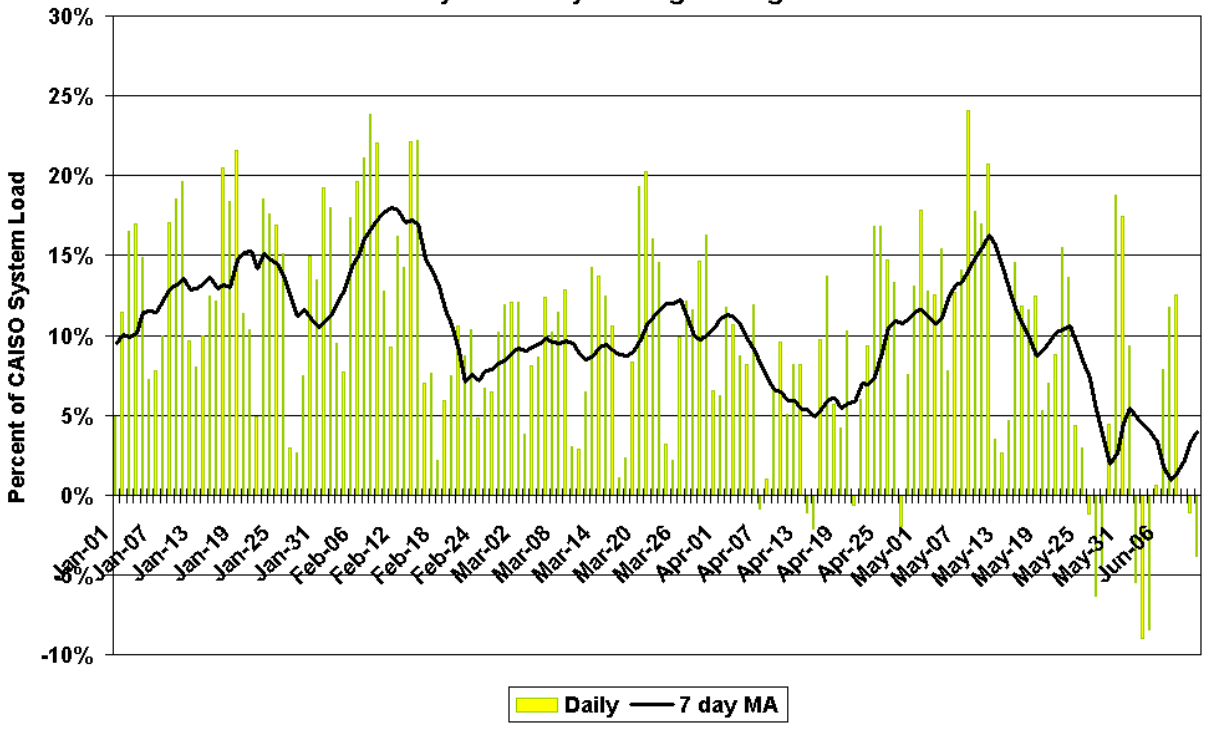
With cooler temperatures and the return to service of several large generating units, scheduled generation and load began to exceed actual load on a number of occasions. These

[1] CDWR did purchase power on behalf of the CAISO on several occasions in December 2000, though at much lower levels.

instances of "overscheduling" have typically occurred on weekends and the first few days of the workweek as demand has yet to reach its peak and as temperatures remain mild.

These occurrences point out the difficulties of attempting to arbitrarily schedule a set percentage of all load and generation one day ahead or contracting 100 percent of the forecast "net short." There is considerable risk that the actual load may be too low if temperatures are lower than expected (in the spring and summer). In these situations, the California Independent System Operator (CAISO) and the CDWR may find themselves in the position of having to either "dec" generation that is already running, or of having to resell a portion of the generation already purchased.

Figure 1
Load Unscheduled Day Ahead
Daily and 7 Day Moving Average



As I showed in the previous analysis, I use the 7-day moving average (black line in Figure 1) in order to smooth out volatility, so that trends are more easily seen. As one can see,

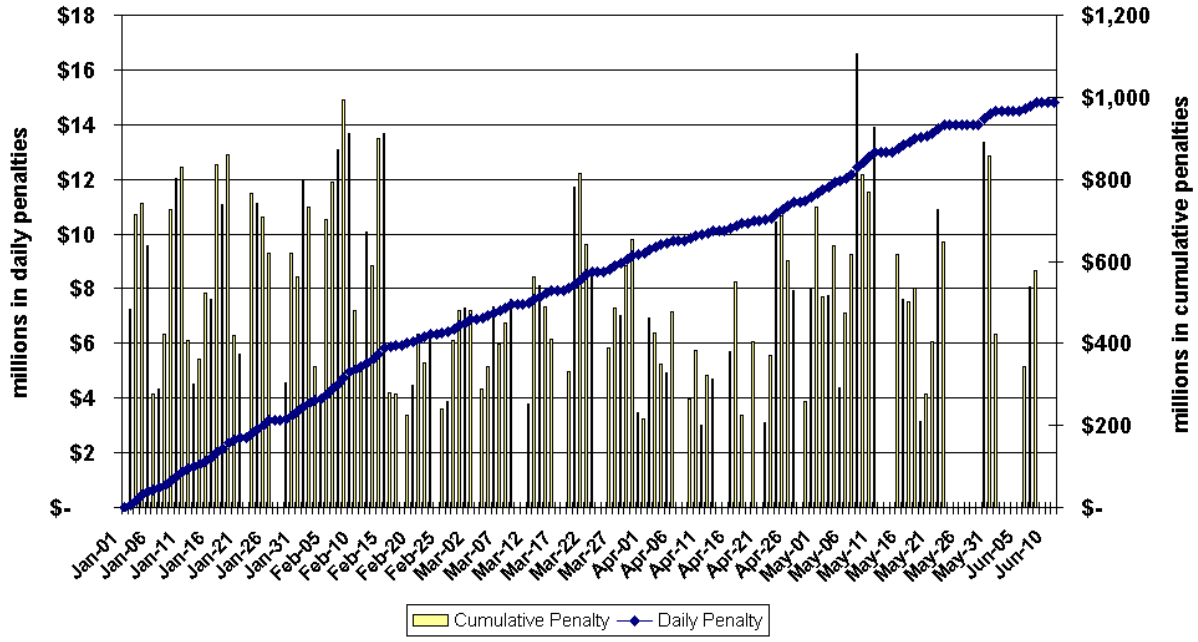
the 7-day moving average was in the range of 10 to 15 percent through much of January. In February, the moving average began to rise before falling in the latter half of February and into March. Through most of March and April, the moving average was in the range of 5 to 10 percent. In May, as temperatures rose and two large nuclear generating units were out of service, the moving average rose, at one point exceeding 15 percent for four days. In this most recent period, the moving average has been in the range of 5 to 10 percent, usually in the upper end of the range[2].

Potential Penalties on Load Pursuant to the Order

My estimate of the potential penalty to load approaches $1 billion dollars for January 1, 2001 through June 12, 2001. From January 19, 2001 to June 12, 2001 (the period in which the CDWR is the purchaser of the "net short" position of the IOUs), the penalty exceeds $800 million. It is our understanding that the most, if not all, of this penalty would be assessed on PG&E and Edison. I show my estimate of the potential daily and cumulative penalties in Figure 2.

[2] I use the 7 day moving average to make two points. First, there is considerable volatility in unscheduled load, with peaks in mid-week and lows typically in the end of week, weekend or beginning of the week. Second, given that volatility, it may not be reasonable to expect an entity to perfectly forecast on a daily basis. I believe that it would be more reasonable to use some averaging method over a week.

Figure 2
Potential Daily and Cumulative Underscheduling Penalties
Imposed Under FERC Order
Since January 1, 2001



Financial Ability of Investor Owned Utilities to Meet "Net Short" Position

Since my earlier review on March 22, PG&E has filed for bankruptcy protection and Edison has signed a memorandum of understanding (MOU) with Governor Davis to sell the State of California its transmission system. A number of conditions must be met before the MOU can be finalized; the most important condition is ratification of the agreement by the State Legislature.

A review of IOU filings with the Securities and Exchange Commission more fully reveals the extent of PG&E and Edison financial liabilities. PG&E reported that it faces over $5 billion in unpaid liabilities through April 30, 2001. Edison reported that it faces over $3 billion in outstanding liabilities through the same period.[3]

[3] PG&E, 10-K, April 17, 2001, Edison, 10-Q, May 15, 2001.

Conclusion

With potential penalties approaching $1 billion and growing daily, one would expect that these penalties would provide a great incentive on certain load serving entities to forward schedule to meet the Order's deadband requirement. However, as I have outlined above, the IOUs are not in financial position to negotiate or sign forward contracts. Even with the resources of the State of California, short term forward contracting appears to be difficult. Moreover, as I have argued previously, the penalty only on load does not provide the proper incentive for suppliers to negotiate forward contracts with generation-deficient load serving entities.

I believe that the continued use of a daily deadband requirement may not be reasonable under normal circumstances and certainly is not reasonable under the circumstances in which the State of California currently finds itself.